## Part 3 - RATE DESIGN

### I. OVERVIEW

One of the necessary steps in restructuring the electric industry is setting rates for T&D utilities. The Act requires the Commission to design T&D rates in a manner consistent with applicable existing law, and directs that this be done in an adjudicatory proceeding. 35-A M.R.S.A. § 3209. This proceeding is the first occasion for the Commission to set rates for a T&D utility. In designing these rates, we are guided by the Act and other existing law, as well as traditional principles of utility rate design. Of particular importance to our decisions on rate design is the fact that the rates will take effect on the same date retail access begins in Maine.

Setting the T&D rates that CMP customers will pay as of March 1, 2000 is just one component of Maine's comprehensive electric industry restructuring. The success of restructuring is important, and our decisions here should promote that objective. At this point, the evidence indicates that, without doing violence to any traditional precepts of rate design, conditions may allow there to be "no losers" on March 1, 2000 - - that is, no customer's bill would increase on that date. Therefore, we adopt two key principles for designing T&D rates: (1) facilitate the transition to a competitive market for generation; and (2) avoid any bill increases.

Maine's electric industry restructuring is more likely to succeed if the public understands and accepts the changes. If T&D rate design implemented concurrently with retail access results in significant bill increases, or substantially disproportionate benefits among customer groups, that acceptance may be difficult to achieve.

We find that a "top-down" method to rate-setting will best fulfill our objective of designing T&D rates that facilitate a smooth and successful transition to retail access. The top-down method we adopt begins with current bundled rates and removes amounts that correspond to the generation portion of these bundled rates. The top-down method is equitable, understandable and will minimize adverse electricity bill impacts concurrent with retail access. We will also adopt CMP's proposal to eliminate the demand ratchet for most customers and will seek to eliminate or reduce the inverted block structure of CMP's residential Rate A to the extent consistent with our principle that no customers should be worse off. Eliminating the demand ratchet and the inverted block structure of Rate A are the only modifications to CMP's rate design that we will consider making effective March 1, 2000. Other changes would be difficult to implement in a way that ensured "no losers". Additionally, we find that the cost studies in this case are insufficiently reliable to support major shifts of revenue responsibility among customer classes.

We will undertake a comprehensive rate design and alternative rate plan proceeding for CMP prior to March 1, 2002. At that time, we can consider experience gained, both in Maine and elsewhere, with the cost structure of T&D utilities after retail access.

Finally, also as directed by 35-A M.R.S.A. § 3209, we establish the structure of rates for CMP customers that take standby service after March 1, 2000. This standby rate structure will apply to T&D backup service that CMP provides to generating stations or facilities and to customers with self-generation. The standby rate structure we adopt, which in essence preserves the rate design currently in effect, comports with our "no losers" principle, while also reflecting the cost responsibility of standby loads for certain fixed cost components of CMP's revenue requirement.

## II. DESIGN OF T&D RATES

### A. Applicable Law and Principles

Before addressing the specific issues before us, we first review the law and principles applicable to rate design, and discuss them in light of the changes occurring in the electric industry. As part of the restructuring Act, Maine's Legislature directed the Commission to design T&D rates "consistent with existing law, as applicable." 35-A M.R.S.A. § 3209(1). The only specific legislative directives regarding the design of electric rates are found in the Electric Rate Reform Act (ERRA). 35-A M.R.S.A. §§ 3151-3155. The ERRA, among other things, requires the Commission to: establish rates that relate more closely to the costs of service, promote maximum efficiency, reflect the marginal cost of service at different voltage levels and time periods, and consider rate design stability. Although the ERRA was enacted at a time of expected generation capacity shortages and rising electricity costs, and was premised on a vertically integrated industry with the monopoly provision of retail generation services,[1] its basic principles of basing rates on costs, promoting economic efficiency and maintaining rate stability remain valid considerations for T&D rate design.

A more detailed articulation of electric rate design principles has developed through prior Commission decisions. *See Central Maine Power Company, Proposed Increase in Rates and Rate Design*, Docket No. 89-068 at 13-15, 21-27 (Jan. 30, 1992) (Docket No. 89-068 Order); *Central Maine Power Company, Investigation into Cost of Service of Customer Classes and Rate Design*, Docket No. 80-066 at 3-14 (Sept. 11, 1985); *Bangor Hydro-Electric Company, Investigation of Cost of Service and Rate Design*, Docket No. 80-108 at 1-7 (Jan. 10, 1985) (Docket No. 80-108 Order). The basic principles established by these decisions can be stated as follows:

[1]As such, some of the language of the ERRA may be modified as part of the conforming amendments to Title 35-A. *See* P.L. 1997, ch. 316, § 11.

- rates should be cost-based;
- rates should reflect cost-causation;
- rates should promote economic efficiency;
- rates should apportion costs equitably;
- rates should be understandable, acceptable, and stable from the customers' perspective.[2]

This statement of rate design principles is also consistent with Bonbright's commonly cited criteria. *See* James C. Bonbright, *Principles of Public Utility Rates, 382-389 (2nd ed. 1988).* Although there is little dispute that these principles constitute the basic criteria for designing rates, they often conflict with one another. Additionally, the principles cannot always be objectively applied. This results in utility rate design often being controversial, requiring the exercise of sound judgment. Thus, setting utility prices can be an application of judgment informed by the technical and economic factors that influence underlying costs.

There are two primary aspects of designing rates: (1) the allocation of the utility's revenue requirement among customer classes, and (2) the design of individual rate elements within classes. Traditionally, most of the emphasis in rate design cases has been on class allocation issues; the same has been true in this case. However, intraclass rate design is as essential to satisfying ratemaking principles as interclass allocations.

An examination of underlying costs is the centerpiece of any rate design proceeding. Two types of studies are generally used in such examinations: marginal cost studies and embedded cost studies. Marginal cost studies are primarily used to design rates that promote economic efficiency and mirror competitive market pricing. Embedded cost studies are used to try to achieve equity by allocating existing costs among customers on a cost-causation basis. Both kinds of studies are tools to be used in the design of rates; their results should never mechanically be applied to determine rates, nor should any study constitute the only ratemaking consideration.[3] Cost studies must also be of sufficient quality and reliability to be used in the ratemaking process, and the overall reliability of such studies must be assessed and weighed in light of all legitimate rate design goals to determine the extent of their use.

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[2]Rate stability in this context refers to the avoidance of substantial or unexpected rate changes, particularly rate increases.

[3]Legislative language and Commission precedent refer to rates "based" on costs. There has never been a policy that rates should precisely "equal" costs for all customers. *See* Docket No. 80-108 Order at 4-5.

B. March 1, 2000 Rates - General Considerations and Approach

We have reviewed the record in light of the rate design goals and principles outlined above. As noted, we conclude that the success of industry restructuring is the primary goal. Our decisions governing the T&D rates that take effect on the same date retail access begins should not undermine that goal. A smooth and successful transition to retail access is more likely to occur if T&D rate design undergoes only minimal change and causes no customers to experience bill increases as a result. No party disagrees with this latter objective. However, the IECG argues that substantial revenue re-allocations and rate design modifications can occur without adverse bill impacts relative to the status quo. This assessment is based on the IECG's view of CMP's revenue requirement in conjunction with the projected benefits resulting from the asset sale to FPL.

We do not disagree with the general proposition that CMP's rate design should be improved to better reflect underlying cost structures. We believe, however, that this can better be accomplished after a year or two of experience with T&D utilities under restructuring. Moreover, to the extent there are benefits available from the sale of CMP’s generating assets, all customers should share.

Finally, we note that significant components of March 1, 2000 electric rates remain unknown. For example, a major component of the stranded cost calculation will not be known until the completion of QF output bidding pursuant to 35-A M.R.S.A. § 3204(4). Additionally, standard offer bid prices, a key component of total electricity rates for many of Maine's consumers, will not be known until December 1, 1999; nor can we adequately project market prices due to delays in implementing the NEPOOL markets and the lack of experience with retail markets in New England.

For these reasons, we adopt a top-down approach to allocate revenue among CMP’s customer classes and design rates. We describe the approach below. To the extent consistent with our “no losers” principle, we will modify the top-down approach to reduce or eliminate the current inverted structure of residential Rate A. We discuss this further in Section E.

C. Top-Down Approach

1. Positions Before the Commission

CMP proposes a top-down approach for allocating its revenue requirement and designing T&D rates for March 1, 2000. CMP advances this approach to minimize customer confusion and adverse bill impacts, goals it believes to be supremely important to the success of industry restructuring. To implement its top-down method, CMP would allocate the revenue requirement reduction resulting from its transition from a provider of bundled service to a provider of only T&D service (i.e., the generation-related reduction) among customer classes based on their relative generation-related costs, and would reduce per-kWh charges to a level that produces each class's T&D revenue requirement. All other rate elements would remain unchanged. Applying the reduction to kWh charges only is premised on CMP's belief that, in the market, customers will typically pay for generation on a kWh basis.[4]

In allocating the generation-related reduction, CMP would reflect generation cost differences among classes based on usage characteristics and line losses.[5] CMP also proposes to account for capacity reserve margins that providers must retain under NEPOOL rules.[6] Finally, CMP states that the best way to identify the factors affecting market costs of power for the different classes would be to rely on standard offer bid prices for individual customer classes. CMP notes, however, that the timing and structure of the current standard offer rule (Chapter 301) would reduce the usefulness of standard offer bid prices for this purpose, but also notes that the structure of the rule is under review by the Commission in Docket No. 98-781.

The OPA agrees with CMP that the fundamental objective of setting March 1, 2000 T&D rates should be to minimize customer confusion and adverse bill impacts so as to promote an orderly transition to retail access. Accordingly, the OPA generally supports CMP's top-down rate design and states that the approach should recognize customer class differences in load factors, load shapes, and provider marketing costs.

The IECG strongly opposes a top-down approach and advocates that customer class re-allocations should be made on the basis of CMP's marginal cost study using a "hybrid" allocation methodology, and that rates should contain higher fixed and demand charges. The IECG questions the goal of minimizing bill impacts, stating that the point of industry restructuring is to promote change. The IECG also questions the Commission's ability to accurately predict generation service market prices for customers and to leave them in the same position as prior to restructuring. The IECG states that T&D rate design should be based on established cost-causation principles and that maintaining the current rate design can only have an accidental relationship to the cost drivers of a stand-alone T&D utility. Throughout the proceeding, the IECG has stated that stability concerns can be addressed by using the available value from the FPL sale so that no customer class will be worse off than it was prior to the rate redesign.

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[4]This method also advances one of CMP's longer-term objectives - to increase the recovery of costs through kW charges. *See* section II(H) below.

[5]Initially, CMP accounted only for line loss differences; but in response to the Bench Analysis, CMP modified its position to reflect usage characteristic-related differences.

[6]CMP indicated that it would update its top-down approach if better information about the market price of electricity becomes known.

2. Analysis and Conclusion

As discussed above, we will adopt a top-down method as our basic approach to setting CMP's core class T&D rates. We agree with CMP and the OPA that promoting the success of industry restructuring by minimizing customer confusion and adverse bill impacts from T&D rate redesign should be the primary consideration.

To implement the top-down method we adopt an approach similar to that proposed by CMP. Non-core T&D revenues will be set by using total pre - March 1, 2000 electric prices and subtracting estimated market prices from these amounts.[7] We will estimate the T&D component of CMP's non-core targeted tariffs and contracts in Phase II. These non-core T&D revenues will be subtracted from the total revenue requirement established in this proceeding, and the remainder will be the revenue responsibility of CMP's core customers. The revenue decrease equal to the difference between revenues at pre - March 1, 2000 bundled rates and the revenue requirement of the new T&D-only utility (i.e. the generation-related reduction) will be apportioned among core customers in proportion to their generation-related costs. Effectively this means that, to the extent there are service territory-wide savings, such as those made available from the FPL sale, they will accrue to CMP's core classes, and not to the non-core discounted targeted tariffs or contracts. The core rates for CMP's LGS-T and LGS-ST classes, which are already substantially less than the applicable price caps, will reflect a generation-related reduction equivalent to 50% of the amount that would be allocated if the bundled rates (actual, not rate caps) were reduced from the top-down with the same method used with all other core rates.[8]

The IECG's comments seem to misconstrue the purpose of the top-down approach. The purpose is not to make electricity consumers indifferent to industry restructuring. Rather, the purpose of the top-down approach is to avoid customer confusion and dissatisfaction that would likely occur if we introduced major changes in CMP's rate structure or revenue allocation. Customers would be unlikely to distinguish between T&D-related bill impacts and the effects of retail access. The top-down approach effectively holds constant the design of regulated T&D rates so that retail access can begin unimpeded by public resistance and its effects not masked by concurrent changes in T&D rate design. This will not hinder the development of a competitive generation market, as suggested by the IECG; on the contrary, it should have the opposite effect, by focusing attention on the opportunities for affecting a customer's bill that are available in the new market.

[7]The market prices may be estimated by using standard offer prices.

[8]To the extent rate caps remain applicable, they should be set for these classes similarly to all other classes using pre - March 1, 2000 caps as the starting point.

We note that the Legislature embraced the concept of a gradual transition to a competitive market by mandating that there be a standard offer for all customers who do not choose a competitive provider. *See* Order Provisionally Adopting Rule, Docket No. 97-739 at 1,3 (Feb. 11, 1998). By using a top-down T&D rate design in conjunction with our authority over the standard offer rate design, we can achieve substantial certainty that standard offer customers will not experience adverse relative bill impacts[9] without hampering development of the competitive market through artificially low standard offer prices. We recognize that we have less ability to affect relative bill impacts of customers not on the standard offer, but the top-down approach will minimize bill impacts relative to a substantial redesign of regulated rates. Finally, we are not aware of any other state that has radically altered utility rate design at the time it introduced retail access for generation services.

Although we generally agree with CMP's method of implementing the top-down approach, there are some aspects we would change. First, the objective is not so much to mirror future market prices, whatever they may be, but to recognize that CMP's revenue requirement is being reduced because CMP will no longer provide generation service; as such, the reduction should be allocated among customers in a manner reflecting their responsibility for CMP's generation-related costs. We believe this may best be achieved by allocating the generation-related reduction among classes in proportion to their generation-related costs. We will also reflect reductions in kW charges as well as kWh charges in classes where our measure of generation cost includes a kW component. As noted above, the objective of the top-down approach is to remove from current rates the revenues currently paid to CMP for generation. These revenues reflect the costs for both energy and capacity and, therefore, the reductions should also reflect both components.

We agree with CMP that the standard offer prices provide a potential guide to implementation of the top-down approach. We are currently considering changes to our standard offer rule to allow greater flexibility for bidders to design prices among customer classes. *Investigation of Standard Offer Rate Design*, Docket No. 98-781. If the rule is modified in this regard, standard offer prices would provide the basis for the top-down reduction.

Finally, we address the application of the top-down approach to CMP’s LGS-T and LGS-ST classes. In CMP’s application of the top-down method, it used current rate caps as the starting point for the generation-related reduction in most classes. However, for two classes (LGS-T and LGS-ST), CMP did not start with the rate caps, but instead used the current actual rates applicable to those classes. For

[9]There will, of course, be great concern if the level of the standard offer bids (as well as market prices in general) causes rates for Maine's consumers to rise substantially at the beginning of retail access. As suggested by the IECG, we have no control over this possibility. But we can moderate overall relative bill impacts among customers and customer classes, particularly standard offer customers.

these two classes, actual rates reflect substantial discounts from the rate caps. In all other core classes, the actual rates and rate caps are identical, or virtually identical. Because actual rates paid by customers taking service from the LGS-T and LGS-ST tariffs are significantly below the rate caps, they already reflect benefits that may become available to other customers from restructuring. Under CMP's application of the top-down approach, this fact would not be captured. However, if we treated LGS-T and LGS-ST like all other core rates by applying the generation-related reduction to their rate caps, the resulting T&D rates would likely cause electricity price increases for these customers -- an outcome that would not comport with our "no losers" principle. Therefore, to balance these considerations, we will allocate to the LGS-T and LGS-ST classes a generation-related reduction amount that is equivalent to 50% of the generation-related reduction they would receive under our top-down approach, and use actual LGS-T and LGS-ST tariffed rates (rather than rate caps) as the starting point.

D. <u>Stranded Cost Charges</u>

Stranded costs are by definition uneconomic costs associated with past actions. They are not affected by and should not affect future usage. From an economic perspective, it is most efficient to recover these costs through charges that are not tied to usage. All parties appear to agree that economic efficiency is promoted by fixed charge recovery of stranded costs and usage sensitive charges that are set closer to actual ongoing costs. Such an approach would lead to more economic consumption decisions, for example, by reducing the incentive for uneconomic bypass that occurs when a customer uses an alternative whose cost is actually higher than the utility's marginal cost.

CMP opposes fixed-charge-based stranded cost recovery in the short term because of bill impacts and implementation difficulties.[10] However, the approach is consistent with CMP's longer-term strategy. It is also generally consistent with the IECG's rate design proposal that would recover stranded costs through demand charges rather than energy changes as a means to allow for consistent recovery for all requirements and standby customers.[11]

However, we will not at this point increase the extent to which CMP's stranded costs are recovered in fixed charges. Doing so would reflect a significant

[10]The Advisory Staff, in their Bench Analysis, asked CMP to explore stratifying classes with separate stranded cost fixed charges for each stratum. CMP concluded that, even with stratification, bill impacts might be unacceptable and there would be administrative problems. Although we view stratification as a potentially useful means to pursue our goal of fixed cost recovery, we decline to adopt such an approach in this case because of complexities and possible customer confusion.

[11]IECG essentially proposes to eliminate kWh charges for most classes. *See* section II(H) below.

change to the existing rate structure and be difficult to achieve in a manner that ensured no losers.

E. Residential Rate A

The rate charged to most of CMP's residential customers (Rate A) currently has an inverted block structure. Specifically, the kWh charge increases by 25% after the first 400 kWhs of monthly usage. CMP lists the gradual reduction of this differential as one of its longer-term rate design objectives, but does not propose to make any change effective March 1, 2000 because of its concern over bill impacts. *See* section II(H) below. The Advisory Staff, in their Bench Analysis, agreed with CMP's position that Rate A should be flattened, stating that there is no cost-based support for an inverted block T&D rate structure. No party disputed the lack of a cost basis for an inverted rate.

We find that no cost basis exists for an inverted block T&D rate structure. Therefore, we will seek to reduce or eliminate the block differential in residential Rate A consistent with our “no losers” principle. The inverted block has been a source of customer confusion in the past and a flattening of the rate is likely to produce a more acceptable and understandable rate structure. However, we will reserve final judgment on the questions of how much, or even whether, the inverted structure should be reduced until Phase II, when we will be better able to assess bill impacts.[12]

F. Demand Ratchet

CMP proposed only one core rate design change to take effect on March 1, 2000. This change would eliminate the demand ratchet for its full requirements commercial and industrial customers. A class's revenue currently collected through the demand ratchet would be reflected in higher demand charges for the class. No party opposed this modification.

We will accept CMP's proposal to eliminate the demand ratchet. The demand ratchet has historically been a source of customer confusion. As proposed, the revenue lost from eliminating the ratchet should be recovered within the same class through higher unit demand charges.

G. Charges for Generators Connected to System

In its surrebuttal case, CMP sought Commission guidance on whether it should develop a new rate for generators that remain connected to its system, but who do not use the system to purchase power from the market or rely on CMP for standby service. CMP states that such entities derive operational advantages from being connected to a large, stable power system. These advantages include helping to

[12]The fact that the standard offer rate design is unlikely to have an inclining structure may make it more difficult to flatten Rate A T&D rates.

stabilize customers' internal generation, and to provide voltage and frequency stability when starting large motors. CMP argues that because such entities derive a benefit from being connected to CMP's system, they should pay a newly established rate that includes a stranded cost component. The IECG strongly opposes such a new rate, arguing that such generators receive no benefit from connection to CMP's T&D system, that it is actually generators (not the T&D lines) that provide voltage and frequency stability, and that such a charge would amount to an exit fee.

The question of whether generators obtain a benefit by virtue of connection to CMP's system is a question of fact that cannot be resolved on the current record. To the extent customers who generate their own power do obtain a benefit from being connected the CMP's system, it would be appropriate that they pay some charge for that benefit; we observe, however, that it is not obvious that benefits flow in only one direction. Should any charge be appropriate, it could reasonably include some stranded cost component. Without additional facts in conjunction with a specific rate proposal, we cannot conclude whether a new rate is appropriate, how such a rate should be designed, or whether it would constitute an unlawful exit fee. We will make these necessary assessments if CMP comes forward with a new rate proposal in Phase II.

## H. Long-Term Rate Design

### 1. Positions Before the Commission

Over the longer term, CMP proposes to move gradually to a T&D rate design that has higher fixed charges and lower usage-based charges. CMP's rationale is that a T&D utility's costs are essentially fixed in the short-term; once the system is built, costs do not vary with energy usage. Therefore, according to CMP, its longer-term proposal represents a more cost-based rate design for T&D utilities. CMP also proposes, as part of its long-term approach, to flatten the existing inverted block structure of its residential Rate A, eliminate seasonally differentiated rates and simplify time-of-use periods consistent with marginal cost drivers. CMP would redesign its rates over time by increasing per-customer and per-kW charges and decreasing to per-kWh charges. CMP suggests it would cap annual individual customer bill increases at approximately the rate of inflation, and notes that, because it expects rates to decrease, steady movement can be made towards an optimal rate design while maintaining a reasonable cap on rate increases.

The IECG generally agrees with CMP's rate design approach of greater fixed and lower usage charges. Specifically, the IECG proposes that the entire customer-related revenue requirement be recovered through fixed monthly customer charges[13] for all classes other than residential Rate A, and that distribution and transmission revenue requirements be recovered through demand charges for those

[13] The IECG believes this will simplify the eventual unbundling of billing and metering costs.

classes with demand meters; thus, its proposed rate design would maintain kWh charges only for residential and small commercial customers.

The OPA disagrees with CMP's long-term objective of increasing fixed charges. OPA witness Anderson testified that some costs associated with the T&D system are energy-related and that it would not necessarily be more efficient to have higher fixed charges because it might discourage conservation.

2. Analysis and Conclusion

We agree with some of CMP's longer-term goals. As discussed above, we will attempt to flatten the currently inverted residential Rate A in the short term consistent with bill impact considerations. If this cannot occur on March 1, 2000, the rate should be flattened as part of longer-term rate design strategy. We also agree with CMP's general proposition that seasonally differentiated rates appear to lack sufficient cost basis for a T&D utility, but that time-of-use rates should be maintained because the structure properly reflects the underlying costs of the T&D system. We also support CMP's proposal that time-of-use rates should be simplified. None of the parties explicitly objected to the merits of these changes.

However, the record does not justify a firm conclusion that we should recover T&D-related costs in increasingly fixed charges. CMP's only justification for this position is that most T&D costs are fixed in the short-run. It is often the case, however, that although a cost is fixed it may nevertheless be related to energy usage. For example, we have consistently considered most of the fixed capital costs of a baseload generation plant as energy related. It may be neither efficient nor equitable to recover costs through demand or customer charges simply because the costs are fixed in the short run. The IECG's position is based on its view that transmission and distribution costs are driven only by peak demands. As discussed in section III(B) below, we are not yet convinced this is the case.

It is certainly possible that a detailed examination of CMP's costs would justify some movement to higher demand or customer charges for T&D-related costs. However, the record in this case does not reveal the extent of such movement, and we make no finding in this regard. We will determine the appropriate degree of these rate design changes in the rate design proceeding we will conduct prior to March 1, 2002.

## III. COST STUDIES AND ALLOCATION METHODS

In this section, we discuss the cost study and revenue allocation issues raised in this proceeding. Although these issues do not affect March 1, 2000 rate design, addressing them to some extent in this Order will provide direction for the post- retail access rate design proceeding.

In this case, CMP presented both marginal cost and embedded cost studies. We explain why neither study supports substantial customer class revenue reallocation on March 1, 2000, and provide guidance for future cost studies. We also address jurisdictional issues regarding transmission cost allocations. Next, we discuss and adopt a method for future stranded cost allocation. Finally, we address the future use of marginal cost and embedded cost studies as the basis for T&D cost allocations.

A. General Methodological Considerations

The restructuring of the electric industry requires us to re-examine previously used costing and allocation methodologies, especially for the transition period in which stranded costs are being recovered. Approaches that worked reasonably well for vertically integrated electric utilities may not transfer directly to T&D utilities, either during or after the transition period.

CMP acknowledges the difficulty in addressing appropriate costing and allocation methodologies and notes that a top-down approach would avoid the need to resolve such issues at the current time. Instead, decisions on T&D costing and allocation could be made after Maine and other jurisdictions have experience with T&D-only utilities and are better able to determine the cost allocation approaches that make the most sense.

In the longer-term, CMP recommends what has been referred to as a "hybrid" methodology[14] to allocate its revenue requirement among customer classes. In the past, the Commission has used as a guide for class allocation a marginal cost allocation methodology in which each customer class is responsible for its class marginal cost, with the difference between total revenue requirement and total marginal cost allocated using the equi-proportional marginal cost (EPMC) reconciliation methodology.[15] *See Maine Public Service Company, Proposed Increase in Rates (Rate Design)*, Docket No. 95-052 at 37-40 (June 26, 1996) (Docket No. 95-052 Order); Docket No. 89-068 Order at 21-27. Due to industry changes, CMP proposes to deviate from the "pure" marginal cost/EPMC methodology and employ the following hybrid methodology:

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[14]The "hybrid" terminology has been used in this proceeding to distinguish between a "pure" marginal cost/EPMC methodology and proposals, such as CMP's, that employ differing methodologies for different categories of costs (i.e., distribution, transmission, and stranded costs).

[15]In practice, the Commission has never approved a “pure” marginal cost/EPMC method; other rate design factors have always come into play.

- customer and distribution costs are allocated based on relative class marginal cost reconciled to total customer and distribution embedded costs through the EPMC methodology.

- transmission costs are allocated using FERC's 12-CP (coincident peak) embedded cost methodology.

- stranded costs are allocated on the basis of relative class revenue contributions at the existing capped rates.

The Company also filed an embedded cost study for informational purposes but does not advocate its use in this or future proceedings.

The IECG agrees with the Company that a hybrid methodology should be adopted. It accepts CMP's methodology for allocating distribution and transmission costs, but disagrees with the Company's allocation of stranded costs. The IECG, instead, proposes to allocate stranded costs 50% on energy usage and 50% on demand.

The OPA questions continued reliance on marginal cost methodologies in a restructured environment, arguing both that it is difficult to achieve the efficiency goal of marginal cost allocations using a hybrid approach and that it is very difficult to accurately quantify marginal costs associated with distribution. The OPA, instead, recommends an embedded cost method to allocate T&D costs. With respect to stranded costs, the OPA proposes a third approach in which the costs would be allocated solely on energy usage.[16]

We agree with the Company that industry restructuring raises new issues in determining costing and allocation methodologies. We also agree that, as long as stranded costs remain a significant component of the revenue requirement, a pure marginal cost/EPMC methodology (based on customer distribution and transmission marginal costs only) should not be used alone. Doing so would result in the allocation of generation-related stranded costs based on the marginal customer and T&D costs -- a result that would be inequitable. We must, therefore, develop allocation methodologies that properly reflect responsibility for the ongoing costs of a T&D utility, as well as for any stranded generation-related costs that the utility continues to recover.

Our decision to employ a top-down approach and not to rely on the cost studies in establishing CMP's short-term rate design is not driven by a desire to avoid these difficult issues; rather, for the reasons discussed earlier, we adopt a top-down approach on its own merits. We do, however, agree with CMP that the parties and the

[16]The Bench Analysis presented other approaches to stranded cost allocations. These are discussed in section III(E) below.

Commission (and, ultimately, ratepayers) will benefit from an opportunity to more fully address the methodological issues raised in this proceeding. In the following sections, we discuss these issues and provide direction for the post-retail access rate design proceeding.

B. Marginal Cost Study

We find that the marginal cost study CMP presented in this case lacks the necessary reliability to support substantial shifts in revenue requirement allocations among customer classes.[17] We discuss below our rationale for this finding and identify areas that must be addressed in the future to improve the reliability of the marginal cost estimates.

CMP's approach to estimating and allocating marginal distribution costs, referred to as the "vintage plant" methodology, uses a regression analysis that relates annual investment in distribution plant to changes in its annual system coincident peak (CP)[18] using 60 years of historical data.[19] This produces a marginal distribution plant unit cost that the Company then converts to a total Company marginal distribution demand cost. This total cost is allocated among classes based on each class's average of CPs and non-coincident peaks (NCPs).[20] Marginal distribution O&M costs are estimated using a single year (1996) of actual expenses. CMP treated marginal meter and service drop costs as customer-related and calculated the costs consistent with previous studies.

We have two primary areas of concern with CMP's study: the marginal distribution plant unit cost estimates produced through the regression analysis; and the allocation of total Company marginal distribution costs among customer classes.

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[17]As noted above, a cost study must be of sufficient reliability to be used in establishing rates. It is inappropriate to use a study that is seriously flawed simply because it provides the only estimates presented in the record. *See generally*, Docket No. 95-052 Order at 4-6, 26-29, 41-43 (reliability of studies taken into account in designing rates).

[18]The annual system coincident peak is the amount of demand at the hour during the year when the sum of all customer demands is the highest.

[19]In a prior proceeding, the Commission adopted this type of regression analysis which relates costs to loads, and stated a preference for use of NCPs rather than CPs. *Investigation of Central Maine Power Company's Resource Planning, Rate Structures and Long-Term Avoided Costs,* Docket No. 92-315 at 63 (Feb. 18, 1994). In a later proceeding, the Commission indicated that it was not prepared at that time to endorse the vintage plant method, over other methods, as a matter of general rate design policy. Docket No. 95-052 Order at 22-23.

[20]The non-coincident peak is the highest demand of a customer class during a time period.

Issues regarding O&M expenses, as well as other miscellaneous issues discussed below, are less serious, but should be examined in future cost studies.

1. Regression Model

The Company's regression model appears to suffer from two basic conceptual problems. First, the Company uses recent experience to separate its system coincident peak loads into the amounts at transmission, and primary and secondary distribution voltages. These amounts are assumed to be constant in a relative sense over the 60-year historical period. CMP has essentially divided annual system coincident peak into three categories, which it sets as constant over time. As a result, the regression analysis really estimates only one equation -- total distribution plant investment as a function of the annual system coincident peak demand. The primary and secondary distribution equations are no more than proportional scalars of this one equation and, thus, do not describe the relationship between investment in primary and secondary distribution plant and load. In other words, the same results could be obtained for the primary and secondary equations by taking a simple fraction of the results of the system CP equation, because they are not independently determined.

Second, the Company's approach is premised on what may be the wrong equation. Witnesses in this proceeding agreed that distribution plant investment is driven, for the most part, by local area peaks. As a result, we find no basis to conclude that changes in the system CP determine adjustments in the amount of distribution plant. It is likely that what the Company's regression equation actually captures is that distribution plant investment grew over time as did the system coincident peak (along with most other aspects of the utility's operation). This point is supported by OPA witness Mr. Anderson, who testified that he obtained equally significant statistical results by simply regressing distribution plant investment on time. Thus, we cannot conclude that the Company's regression analysis supports its basic premise that distribution costs are driven by peak demands at the time of the system peak.[21] We are also concerned that the Company has not provided evidence of the absence of autocorrelation problems with its equations.[22] Given Mr. Anderson's results using timetrend analysis, it is reasonable to expect a high degree of autocorrelation of the error terms in the Company's equations. Correcting for such autocorrelation could

[21]In responding to intervenor arguments regarding diversity in establishing standby rates, CMP stated that system peak "is not relevant for individual distribution circuits." CMP Reply Brief at 72 n.37. (emphasis in original)

[22]Autocorrelation refers to the error terms associated with observations in a given time period that carry over to future time periods. This represents a violation of one of the underlying assumptions of ordinary least squares regression; that the error terms are statistically independent.

be expected to adversely affect the statistical significance of the estimated coefficients, i.e., the marginal investment estimates.

The Company attempts to account for the impact of local area peaks on marginal distribution costs by allocating these costs among the classes, in part, on the basis of class NCPs as well as CPs.[23] However, this resolution is unsatisfactory; it does not correct for the fact that the Company's marginal distribution unit cost estimates remain premised on an assumption that they are driven by usage at the system CP.

For the reasons discussed, we would be unlikely to rely on the Company’s distribution plant investment regression estimates, which provide the major component of the Company’s marginal distribution costs.

2. Planning Criteria for Distribution Plant Additions

The Company's unit distribution plant estimates and class allocations are especially troublesome in light of its stated planning criterion for the distribution system. The Company maintains that there are no diversity benefits in planning for distribution capacity to serve large loads (above 400 kW).[24] This position further calls into question the reasonableness of the regression estimates of unit marginal costs derived using system coincident peak. Based on CMP's stated planning criterion, the relevant loads would be the coincident local peaks of small customers and the maximum potential demands of large customers. Moreover, the Company's stated planning criterion leads to the conclusion that its marginal cost study erroneously allocates distribution costs because it uses relative class CPs and NCPs, rather than maximum potential demands for classes above 400 kW and the relevant coincident demands of classes below 400 kW.

The Company states that distribution capacity investments to meet the load of a large customer on a distribution circuit are driven by that customer's maximum potential demand. The Company treats larger customers in the same manner for planning purposes, regardless of whether they are standby or full requirements customers (sufficient capacity is maintained to meet 100 percent of a larger customer’s load without regard for diversity). Based on the Company's planning criterion, the load that drives distribution investment is the coincident load of all small customers on a circuit plus the maximum potential individual loads of large customers on the circuit, rather than system coincident peak as assumed in CMP's regression

[23]NCPs have been used in prior studies as a proxy for local area peaks.

[24]This matter was raised by CMP in justifying its standby rate proposal and we discuss it in detail in section IV below. At this point, however, we should observe that the evidence of whether CMP does, or should, take such diversity into account is conflicting.

analysis. Accordingly, in conducting future cost studies, the Company should explore methodologies that account for the relationship between distribution investment and its stated planning criterion. The Company should also reflect this planning criterion in its allocation of distribution costs among customer classes.

### 3. Energy Relationship to T&D Costs

#### a. Positions Before the Commission

The Advisory Staff, in their Bench Analysis, raise the general question of whether some portion of T&D costs should be allocated to classes based on energy use. The issue was raised in the Analysis, in part, because CMP's approach does not allocate any of the costs of the T&D system according to the use of energy, even though the system exists to deliver kWhs of energy to end users. The Staff reasons that, although incremental costs are incurred to meet elevated demands, this does not mean that all distribution costs are demand-related. Such a finding would lead to the conclusion that customers who never use the system during peak hours should be able to use the system for free.

The Staff notes that distribution plant was constructed primarily to deliver energy to customers during all hours of the year, not just at the times of the peaks; the system exists and related costs are incurred to deliver electricity to customers whenever it is desired. If energy were needed only several hours each year, it is likely that the current T&D system would not have been constructed; consequently, some significant portion of the capital costs of the T&D system should be allocated on energy use.

The Staff suggests that CMP's 65% system load factor and 60% load factor for distribution-voltage customers provide a logical basis to determine the energy share. The load factor is the ratio of average demand to peak demand; average demand is also a measure of energy use. Therefore, the Staff indicates that it is reasonable to use load factor to divide T&D costs into energy-related and peak demand-related components. This is because, if there were no variance in the hourly demands on the system, its capacity would have to be designed to meet the annual energy demand (i.e., average demand); costs to meet additional demands are appropriately considered demand-related. Rather than relying on load factor, however, the Staff proposed to deviate somewhat less from past practice by splitting costs on a 50/50 basis between energy and demand.[25]

CMP and the IECG criticize the suggestion that some portion of T&D plant should be allocated on energy. The other parties did not address this issue. With respect to transmission, the Company states that costs must be allocated according to FERC's methodology, which uses a 12 CP allocator. We

[25] This proposal applies to both embedded and marginal studies.

discuss the implications of FERC's jurisdiction over the allocation of retail transmission cost in section III(D) below.

The Company's position regarding distribution costs is that upgrades to the system are made solely in response to peak demands. As a result, the marginal cost of distribution is appropriately defined as the additional investment made in response to an increase in peak demands. In the Company's view, energy use has no responsibility for marginal distribution costs and an energy allocation would have no cost basis. Finally, the Company notes that no jurisdiction has allocated an electric utility's distribution costs on the basis of energy usage.

The IECG recognizes that the delivery of energy must be taken into account in planning the T&D system. However, the IECG argues that the energy component of system expansion decisions relates to the analysis of how probable it is that certain demands will, in fact, have to be met. Therefore, according to the IECG, the energy aspect of system planning is already incorporated in the demand component through the recognition of class diversity and reliability standards; as a result, T&D investments are already limited to items that can be justified on an energy basis.

b. Analysis and Conclusion

We are not prepared, based on the record before us, to reach a definitive answer on this issue. For the reasons discussed below, however, we will consider, in the next rate design proceeding, whether energy should be reflected in T&D costs. We have previously decided, for example, that certain high voltage transmission line investments are energy-related and, thus, not marginal with respect to demand. Docket No. 89-068 Order at 38-39. The question we will address is whether other portions of the T&D system are energy-related and marginal with respect to energy usage.

In the theoretical long-run, all costs are considered variable. Thus, it seems clear that some portion of T&D system costs is marginal with respect to energy. When decisions are made whether to build a particular portion of the distribution system or whether to build an integrated system at all, the amount of energy over which the costs of the system investment can be spread must enter the decision. For instance, if energy were used in CMP’s service territory in only twelve hours of the year, it is unlikely that the current T&D system would exist. It is the sustained use of energy, to some significant degree, that results in the investment to construct the system.

The significance of energy as a driver of T&D costs may be viewed in two ways. First, from a long-run marginal cost perspective, is there reliable data showing that energy use, as distinct from demand (even when diversity is taken into account), makes any difference to the design and construction of the T&D system?

Second, whether or not energy is a "cost" driver, the relative energy use among customers may nevertheless inform our judgment concerning the equitable allocation of costs (such as common overheads, embedded costs in excess of marginal costs, and stranded costs) among customer groups. In the rate design proceeding we will undertake after retail access, we will thus explore methodologies that identify the relationship of energy use to marginal distribution cost in estimating unit and total costs, and ways to allocate total distribution costs (including the reconciliation amount) among customer classes.

4. Miscellaneous Issues

Three additional issues were raised regarding the Company's marginal cost study. OPA witness Anderson questions CMP's use of recent average O&M expense as a proxy for marginal O&M costs. Mr. Anderson's concern is that this approach assumes there are no economies of scale or scope and, thus, it overestimates this cost component. The Company responds that there is no empirical evidence that there are such economies and that marginal O&M costs are less than average O&M costs. The Company also argues that its method is regularly used and is recommended by NERA. The OPA has raised a legitimate issue that should be fully addressed in the post-retail access rate design proceeding. Specifically, CMP should consider whether such economies exists and, if so, how they should be measured.

The Advisory Staff, in their Bench Analysis, questioned the Company's use of only a single year to estimate marginal O&M costs rather than the 5-year average used in previous cases. The Company notes that this change was made because Mr. Caron and Ms. Dufour performed a thorough examination of its 1996 costs as part of their separations study and this analysis was not performed for any other year. Although this explanation is not unreasonable, the Company should revisit the question of how best to estimate O&M costs, including the issue of the existence of scale and scope economies in the future cost studies.

Finally, the Staff also questioned the Company's use of system probability of peak rather than class NCPs to assign distribution costs to rate periods. The Company argues convincingly that it is the time pattern of loads on local distribution circuits that is relevant. CMP states that, in its service territory, distribution equipment normally does not serve customers from a single class. As a result, it appears inappropriate to use class NCPs to assign these costs to rate periods. However, we are not convinced that system probability of peak properly assigns these costs to periods. System-wide load variations may have little to do with these variations on local circuits. Indeed, selected probability of peak data for individual substations provided by the Company show significant variation in the time patterns of local loads. We direct the Company to consider this issue in greater depth when it prepares its next marginal cost study.

C. Embedded Cost Study

As noted above, relatively little attention was paid to the Company's embedded cost study. A great deal of additional scrutiny of the study would be needed before the results could be relied upon for class allocations. Nevertheless, we note that the results of the Company's study, either with or without a modification to include an energy allocation of 50% of the T&D costs, does not support a significant re-allocation of revenues among classes.

The Advisory Staff's Bench Analysis and OPA each raised several issues that we discuss below. Some of these issues are the same as those raised regarding the marginal cost study, and we need not repeat the discussion in detail. We will limit our discussion to three issues: (1) the energy allocation of T&D costs; (2) the appropriate demand allocator for large customers; and (3) the appropriate allocator for A&G expense.

1. Energy Allocation

For the reasons discussed above in the context of the marginal cost study, we will again consider whether it is appropriate to allocate any portion of T&D embedded capital costs on the basis of energy use. Whatever the merits of using energy in a marginal costs study, there may be some independent merit to taking energy use into account in an embedded study, whose goal is to allocate historic costs on a cost-causation basis. Accordingly, the question would be what usage characteristics caused T&D plant to be built in the first place. In CMP's next embedded study, we will look for a thorough discussion of this issue.

2. Demand Allocator for Large Customers

If we accept the Company's representation that distribution capacity is planned to meet the maximum potential loads of large customers without regard to the diversity of those loads, we must conclude that distribution demand-related costs have been improperly allocated in both the Company's marginal and embedded cost studies. The allocation should be based on how the Company actually plans and constructs the system, because that is what drives costs. The appropriate distribution demand allocator, therefore, should be the sum of coincident demands of small customers on local circuits plus the sum of the maximum potential demands of large customers. If no costs are allocated on energy, the appropriate allocator should be the small classes' NCPs plus the sum of the individual customer maximum demands of classes of customers with demands greater than 400 kW.

3. Allocation of A&G Expense

OPA witness Anderson challenged the Company's assumption that all A&G expense should be allocated to classes in proportion to payroll expense. He asserts that the Company's own separation study demonstrates that approximately

30% of these costs should be allocated on plant rather than payroll expense. He argues that the use of payroll expense will result in overcharging the residential class for these costs. The Company counters that its payroll method is a standard allocation recognized by NARUC. It further contends that its method is an allocation based on assumptions, rather than direct cost causation and that any alternative to allocate A&G, such as suggested by Mr. Anderson, would simply be based on a set of new assumptions.

These arguments do not persuade us to reject Mr. Anderson's alternative. However, in its exceptions, CMP notes that its method may indirectly capture an appropriate weighting of plant because the payroll expense amounts are allocated, in part, using plant allocations. We will explore whether the Company's approach properly accounts for the plant-related portion of A&G expense in the post-retail access rate design proceeding.

D. Transmission Costs

1. Jurisdiction

CMP asserted throughout this proceeding that FERC has exclusive jurisdiction over retail transmission rates by virtue of the State's decision to unbundle generation as a separate product. The IECG agreed with this position and no party disputed it. The Advisory Staff, in their Bench Analysis, questioned whether FERC would have jurisdiction over the transmission component of a "bundled" retail T&D service in which transmission is not unbundled as a separate retail product.

We have carefully reviewed FERC's discussion of this matter throughout its Order No. 888 and have concluded that, although its language is often ambiguous, FERC's intended conclusion is that it has exclusive jurisdiction over the rates, terms, and conditions of retail transmission rates when generation is unbundled and offered as a retail product separate from "delivery service." FERC Docket Nos. RM95-8-000, RM94-7-001 (April 24, 1996). However, FERC has explicitly stated a willingness to defer to the needs of state retail competition programs. CMP claims that this deference was intended to include only minor deviations from FERC open access tariffs and transmission pricing policies. In our view, CMP's interpretation of FERC's statements is overly restrictive; FERC has left the door open for utilities and states to request retail transmission rates, terms and conditions that meet state needs and policies. It appears that, upon reasonable justification, FERC will provide substantial deference regarding retail transmission filings made pursuant to state retail competition programs as long as they are consistent with FERC open access policies.

In Order No. 888, FERC explained why its authority attaches only to unbundled, but not bundled, retail transmission in interstate commerce:

> [W]hen transmission is sold as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail. Under the FPA, the Commission's jurisdiction over sales of electric energy extends only to wholesale sales. However, when a retail transaction is broken into two products that are sold separately (perhaps by two different suppliers: an electric energy supplier and a transmission supplier), we believe the jurisdictional lines change. In this situation, the state clearly retains jurisdiction over the sale of the power. However, the unbundled transmission service involves only the provision of "transmission in interstate commerce" which, under the FPA, is exclusively within the jurisdiction of the Commission. Therefore, when a bundled retail sale is unbundled and becomes separate transmission and power sale transactions, the resulting transmission transaction falls within the Federal sphere of regulation.

*Id.* at 246-247. In other portions of the Order, FERC defines retail wheeling services as the delivery of electric energy that includes two components: transmission and local distribution. FERC asserts jurisdiction over transmission facilities, while indicating that states have jurisdiction over local distribution facilities. *Id.* at 229 n.515, 516, 244-253.

The FERC Order, taken as a whole, reveals an intent to exercise exclusive jurisdiction over the rates, terms, and conditions of the retail transmission component of delivery service, if generation is unbundled and offered as a separate product. As a result of its jurisdiction, FERC stated that rates, terms and conditions of retail transmission must be filed with the agency. *Id.* at 252.

Despite its claim of exclusive jurisdiction, FERC repeatedly emphasized its desire to promote state/federal cooperation and rely on state expertise, as well as a willingness to defer to state retail competition programs where appropriate.

> While the Commission cannot simply turn over its jurisdiction for the states to implement, we understand the concerns raised by many state regulators and believe that deference to state commissions with regard to rates, terms, and conditions [for retail transmission service] may be appropriate in some circumstances . . . .

*Id.*

FERC explicitly stated that, although it "generally expects" unbundled retail wheeling customers to take service under the same tariff as wholesale customers, it may be appropriate to have a separate retail transmission tariff with different terms if unbundling occurs as part of a state retail access program.[26] *Id.* at 252. FERC further explained:

> In such situations, the Commission will defer to state requests for variations from the FERC wholesale tariff to meet these local concerns, so long as the separate retail tariff is consistent with the Commission's open access policies and comparability principles . . . .

*Id.;* see also *Id.* at 98.

In addition to stating its general willingness "to give deference to state recommendations regarding rates, terms, and conditions for retail transmission service," *id.* at 98, FERC specifically referenced several areas where deference may be provided: transmission cost allocation between retail and wholesale customers; allocation of costs between transmission and distribution facilities; and the determination of transmission and distribution facilities for jurisdictional purposes. *Id.* at 251.

As long as a state fosters FERC's general policy of promoting electric market competition (as Maine's restructuring effort clearly does) and state recommendations are consistent with FERC's policy of non-discriminatory, open transmission access, FERC is reasonably likely to defer to state views regarding the implementation of state retail access programs.[27] This is especially likely in areas of traditional state concern, such as customer class allocations and rate design for retail ratepayers taking a regulated service from its local utility. As stated above, FERC has expressed a willingness to defer to states regarding cost allocations among wholesale and retail customers, and among transmission and distribution facilities. It is, thus, reasonable to assume a similar deference regarding a state's allocation and rate design among retail customer groups.

It appears that deference to states' policies regarding cost allocation and rate design in the context of establishing a T&D utility's rates for retail service within its local territory would not be inconsistent with FERC open access policies or offend its comparability principles. If a retail customer in another state desires to purchase transmission through CMP's territory so that it can access a remote generation provider, that customer would be eligible to purchase under CMP's pro forma open access tariff. This would provide for comparability between retail and

[26]FERC stated that unless a separate retail transmission tariff is on file, its pro forma tariff must include retail transmission customers as eligible. *Id.* at 98.

[27]FERC stated that "[a]lthough the Commission believes its Final Rule will accommodate retail competition . . . our policies relate only to the bulk power market and not traditional state regulation of the retail market." *Id.* at 248.

wholesale transactions that require transmission through CMP's territory. However, in this case, we are establishing combined T&D utility retail rates for a monopoly service applicable to customers within the utility's local service territory. Because all retail customers within the service territory will purchase bundled T&D service from CMP at regulated rates, customer class revenue allocations and intraclass rate design will not implicate FERC's non-discriminatory open transmission access policies.

The precise implications of FERC's jurisdiction over retail transmission to the issues in this proceeding are unclear. It appears that CMP will have to make a retail service filing at FERC;[28] otherwise, all its retail customers (including residential and small business customers)[29] would have to take retail transmission service under the rates, terms and conditions of its pro forma open access tariff. CMP, however, never explained the implication of FERC jurisdiction in light of its top-down approach to rate design. One option may be for CMP to file its retail T&D tariff, including terms and conditions of service, at FERC without an explicit unbundling of transmission rates. Another approach might be to file unbundled retail transmission rates (with corresponding terms and conditions) consistent with the top-down T&D rate design. If so, the rates in this case could be established on a residual basis as the difference between the top-down rates and the unbundled transmission rates. This matter will be addressed in the transmission investigation discussed below.

With respect to future cost of service proceedings, we anticipate that FERC would defer to our retail costing and rate design policies. If so, transmission cost allocation and rate design would be consistent with our policies stated in this and future orders.[30] If FERC acts to preempt our policies in this regard, then transmission costs would be separately allocated within the type of hybrid methodology proposed by CMP and the IECG.

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[28]As noted in Part I, it appears that CMP will have to file at FERC to establish its transmission revenue requirement.

[29]Under the FERC tariff, these customers would have to be charged for transmission through a per-kW charge. That would not be feasible because these customers do not have demand meters. Accordingly, we presume FERC will allow this deviation from its tariffs even though the conversion to a kWh charge would have the necessary effect of re-allocating costs within the class relative to FERC's 12 CP allocation, an action that CMP insists FERC would not allow as between rate classes.

[30]During the proceeding, it was suggested that the FERC-established rates might be considered CMP's marginal transmission cost and become part of the EPMC reconciliation. CMP and the IECG opposed this concept. If the FERC defers to our costing methodologies, the actual marginal cost of transmission could be calculated, rather than assuming that the FERC rates are the marginal costs. In the alternative, FERC's embedded methodology could be used as part of a hybrid methodology as proposed by CMP and the IECG.

2. Investigation

Based on our conclusion that FERC has asserted jurisdiction over retail transmission when generation is unbundled, we will open an investigation into transmission matters, as proposed by CMP.[31]

As mentioned above, FERC has sought state expertise in determining jurisdictional lines between transmission and distribution facilities, and has stated that it would defer to state recommendations in this regard. For this purpose, FERC has articulated seven indicators of local distribution to be evaluated case by case:

(1) Local distribution facilities are normally in close proximity to retail customers;

(2) Local distribution facilities are primarily radial in character;

(3) Power flows into local distribution systems; it rarely, if ever, flows out;

(4) When power enters a local distribution system, it is not reconsigned or transported on to some other market;

(5) Power entering a local distribution system is consumed in a comparatively restricted geographical area;

(6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system;

(7) Local distribution systems will be of reduced voltage.

*Id.* at 230.

FERC requires utilities to consult with their state regulatory authority "as a prerequisite to filing transmission/local distribution facility classifications and/or cost allocations with the Commission," and encourages public utilities and their state commissions to attempt to reach agreement in these areas. *Id.* at 251. FERC indicated that if the "utility's classifications and/or cost allocations are supported by the state regulatory authorities and are consistent with the principles established in the Final Rule, the Commission will defer to such classifications and/or allocations."[32] *Id.*

[31]CMP suggested we open a generic rulemaking on transmission issues. We believe an investigation would be a more appropriate procedural vehicle.

[32]FERC indicated that the states should specifically evaluate the seven

Because of our desire to work cooperatively with FERC, a primary purpose of this investigation will be to consider the proper split between state and federal jurisdictional facilities, along with appropriate cost allocations. The desired end result would be utility filings at FERC that we could support. These filings could also be a vehicle for utilities to present their transmission revenue requirement, as well as retail rates, terms and conditions for FERC approval.

As part of a generic transmission proceeding, CMP suggests that the following issues be explored:

- Whether customers should have the opportunity to purchase transmission services pursuant to the appropriate open access transmission tariff (OATT), or whether transmission services should only be included with local distribution services in retail T&D rates.

- Whether load-serving entities that provide electric energy to Maine customers can include transmission services with their generation services; in other words, can load-serving entities purchase transmission services on behalf of their customers, with the result being that the T&D utility would not charge these customers for transmission services;

- Whether transmission providers will be hurt if customers or load serving entities can choose to take transmission services under the appropriate OATT and, if so, whether the Commission should permit Maine utilities to reconcile FERC-approved transmission revenue requirements with actual recoveries so transmission providers are not hurt by the selections; and

- Development of a process for filing the rates, terms and conditions of unbundled retail transmission service with FERC.

We agree with CMP that these types of issues should be explored and will include them in our investigation.

E. Stranded Cost Allocation

1. Positions Before the Commission

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indicators, but noted that there could be other relevant factors. *Id.* at 251 n.548.

Several approaches to allocating stranded costs among customer classes were proposed in this proceeding.

CMP states that, under its top-down approach, stranded costs are recovered in the same manner as in the past. Over the long term, CMP proposes to allocate stranded costs among customer classes based on relative class revenue contributions at the Company's existing rate caps. Under this approach, if a class (during a test year) contributes 40% of the Company's revenue at the capped rates, then 40% of stranded costs would be allocated to that class. CMP views this approach as equitable in that it tempers revenue realignments and strives to preserve the current rationale for cost allocation. CMP states that at the time stranded costs were being incurred, the Commission was making decisions regarding allocations, and those past decisions should form the basis of stranded cost allocations in the future.

The OPA proposes that stranded costs should be allocated on energy usage, because the costs were incurred primarily to serve energy requirements. The OPA supports its position by noting that stranded costs are primarily associated with baseload resources (e.g., QF contracts, nuclear plants) and that no peaking plants are included in stranded costs. The OPA opposes the Company's current rate cap approach, because, over time, it could produce stranded cost allocations based in part on T&D costs.

The IECG proposes that stranded costs be allocated 50% on energy and 50% on demand. The IECG's view is that stranded costs were incurred to meet both energy and capacity needs and that a 50-50 split is a fair balancing for allocation purposes because it is not possible to resurrect the relative needs for energy and capacity in the past or the resulting investments that resulted in CMP's stranded costs. The IECG proposes the use of the NEPOOL formula to allocate the capacity portion because this reflects the manner in which NEPOOL assigned capacity responsibility during periods when most of the stranded costs were incurred.[33] For energy, the IECG proposes using relative class energy consumption.

The Advisory Staff, in their Bench Analysis, also offered an alternative allocation of stranded costs based on a combination of energy and demand.[34] This approach (like that of the IECG) recognizes that stranded costs are generation-related and thus have an energy and capacity component. To explore a basis for determining the relative weighting of energy and capacity with respect to how

[33]The NEPOOL formula weighted annual system peak and the average of 12 monthly peaks by 70% and 30% respectively.

[34]The Bench Analysis provided a further alternative in which stranded costs are allocated based on stranded cost levels implied by the difference between current rate caps and the newly established T&D class allocations, but concluded that such an approach would simply offset the effect of any T&D revenue reallocation.

the costs were incurred, the Bench Analysis presented a review of recent CMP marginal cost studies and CMP's projection for market prices in the year 2000. This review showed an energy/capacity ratio ranging from 80/20 to 70/30. Based on this analysis, the Staff concluded that it would be reasonable to allocate stranded costs 75% on energy usage and 25% on demand.

The Staff also notes that nuclear decommissioning costs present a unique category of costs. Although they are costs of the T&D utility, they are clearly generation-related. As such, the Staff suggests that these costs should be allocated in the same manner as stranded costs.

2. Analysis and Conclusion

For the purpose of developing rates for the T&D utilities, we have essentially adopted CMP's approach. Because rates are calculated on a "top down" basis, each customer's responsibility for stranded costs should be close to the responsibility prior to the advent of competition. This approach, in addition to minimizing bill impacts and customer confusion, reflects the mandate in 35-A M.R.S.A. §3208 (5) that utilities should have an opportunity to recover stranded costs that is comparable to the opportunity they had prior to retail access. By declining to change the rate design for stranded cost recovery, we preserve the status quo to the greatest extent possible.

To the extent that, in the future, stranded costs are directly allocated to classes, an allocation reflecting both energy and demand would be appropriate. Specifically, an allocation of stranded costs based 75% on energy and 25% on demand appears to reflect a reasonable weighing of these components.

Stranded costs are previously incurred, uneconomic generation-related costs. All of the proposed stranded cost allocation methods presented in this case seek to apportion the costs among classes based on equity considerations, and attempt to relate allocations either to why the costs were incurred or to how the Commission previously set recovery.[35]

CMP's approach seeks an equitable allocation by reference to current rate cap revenue. However, the current rate caps are a result of a marginal cost based allocation with an EPMC reconciliation to CMP's total revenue requirements. The allocation also reflects substantial rate stability smoothing and

[35] CMP notes that, if efficiency is the focus, inverse-elasticity principles could be applied. CMP does not recommend using such an approach because allocating based on relative class elasticities would be controversial. It states that elasticities are better accounted for through more targeted pricing flexibility efforts. We do not disagree with CMP in this regard, but add that reflecting inverse-elasticity principles in the design of rate elements may also be an option; this may be preferable to allocating class revenue responsibility on this basis, which requires gross generalizations about customer class elasticities, and is a less direct way to affect usage.

several subsequent across the board allocations of rate increases. For this reason, it is difficult to place too much weight on the notion that current rate cap revenues represent prior Commission allocation of CMP's stranded costs. Nor can it be viewed as preserving any cost allocation rationale that was in place at the time stranded costs were incurred, since stranded costs were incurred over many years. Additionally, CMP's approach results in allocating generation-related costs based on factors having nothing to do with the cause of those costs (e.g., relative customer and distribution costs).

To achieve equity objectives, these costs should be allocated in a manner consistent with the reasons they were incurred. Because stranded costs are generation-related, it is appropriate to allocate them on the basis of a mix of energy and capacity consistent with the requirements of CMP's system. We disagree with the OPA that costs should be allocated entirely on energy. Although CMP's stranded costs are most often associated with resources that could be characterized as baseload, these resources contain a capacity component. Moreover, what we are allocating are CMP's net stranded costs that reflect the total of CMP's generating resources; accordingly, the relative amounts of capacity and energy in these costs are best measured by CMP's system requirements over time.

We also disagree with the IECG's proposed 50-50 split, which is based on an assumption that there is no reasonable basis to determine an appropriate split. Our view is that an examination of CMP's prior marginal cost studies and market price projections, as contained in the Bench Analysis, provides a sufficient basis for weighing the components. We find this approach to be preferable to an arbitrary 50-50 split. It is also consistent with the "peaker methodology" that we adopted in the past to unbundle and allocate generation costs. This methodology identifies the capacity component of generation as the least-cost means to meet peak demand. *See* Docket No. 89-068 Order at 29-34. Accordingly, we find the Staff proposal of a 75%/25% weighting of energy and capacity to be a reasonable approach. The allocation method for each component would be as proposed in the testimony of IECG witness Dr. Silkman: energy based on relative class energy consumption and capacity using the prior NEPOOL 70/30 weighted annual and monthly peak formula.

We also agree with the Staff's suggestion that it would be appropriate to allocate nuclear decommissioning costs in the same manner as stranded costs. Decommissioning costs are clearly generation-related and are part of the transition to an unregulated generation market.[36]

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[36]CMP also proposed that DSM expenses be characterized as stranded costs for allocation purposes. As discussed in Part 2, DSM costs incurred prior to March, 2000 are generation-related costs. Accordingly, we have determined that the available value from the asset sale should be used to offset a substantial portion of prior DSM costs. To the extent such costs are not offset by the available value from the asset sale (e.g., amounts that will be paid for in the future), they should be allocated in the same manner as stranded costs. New conservation costs under 35-A M.R.S.A. § 3211,

F. Future Use of Cost Studies

In a major CMP rate design proceeding conducted more than 10 years ago, we found that electric rate design should primarily be based on marginal costs employing an equi-portional approach for class allocations (EPMC). Docket No. 89-068 Order. We did, however, require the continued filing of embedded cost studies, at least on an interim basis, as a secondary source of information. *Id.* at 23, 50-51. Embedded studies have had little influence in recent cases. *See* Docket No. 95-052 Order. For the reasons discussed below, however, we will require the post-retail access rate design case filing by CMP to include both marginal and embedded cost studies, and leave for that case the decision as to their use in rate re-designs.

1. Positions Before the Commission

All of the parties appear to agree that, if reliably estimated, marginal costs provide a superior basis for the determination of economically efficient prices. The OPA, however, argues that embedded cost allocations are superior in achieving an equitable allocation because, in part, they match class revenues to cost responsibilities. In the OPA's view, no such matching is provided by the use of marginal costs and an EPMC reconciliation. For example, use of the Company's marginal cost study systematically shifts responsibility for costs to the residential class by arbitrarily inflating the customer related share of the revenue requirement.

The OPA also argues that there is no generally accepted methodology for measuring marginal T&D costs. The Company does not have a complete and systematic set of marginal cost estimates; transmission costs are allocated using FERC's embedded costs, and distribution O&M and customer-related expenses are essentially average embedded costs. Consequently, CMP and the IECG essentially propose to use a combination of average embedded and marginal costs to arrive at a set of class revenues that will equal the total jurisdictional revenue requirement.

CMP and the IECG argue for the continued reliance on marginal costs and EPMC as the basic approach to class allocations on the grounds that this methodology best promotes the economic efficiency of rate design. CMP also suggests that the ERRA may require this approach, in that it refers to rates that reflect marginal costs. 35-A M.R.S.A. § 3153-A(1)(B). CMP responds to the OPA's concerns by stating that, just because a price signal is not perfect, we should not abandon the goal of efficient pricing. Finally, CMP argues that there are no particular advantages to an embedded costs approach, and its use would lead to substantial new controversies over what are inevitably arbitrary allocations.

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however, are not generation-related, but are social costs analogous to low income program costs. These will be allocated as part of CMP's non-stranded cost revenue requirement.

2. Analysis and Conclusion

Our review of the record and the arguments of the parties in this case indicates there are valid reasons to re-evaluate the methods that were previously used for vertically integrated utility rate design before applying them to T&D utility rate design. For example, past marginal cost studies, and our reviews thereof, have focused most heavily on the generation component. This is understandable because generation costs were such a large component of the total. Methods to estimate and allocate generation-related costs received significant attention and were well developed. In contrast, it does not appear that a way to reliably measure marginal distribution costs has been developed.

Additionally, there are reasons to reconsider whether our traditional marginal cost/EPMC allocation can serve the purposes for which it was originally adopted during the next several years when stranded costs will be a major component of revenue requirements. The EPMC methodology was originally adopted as the best means to promote economic efficiency and create proper price signals The approach was also considered equitable because each customer would pay the going-forward cost of providing service plus a proportionate share of the reconciliation amount. However, no party has proposed that CMP's entire revenue requirement (including stranded costs) be allocated by EPMC.[37] Rather, parties proposed hybrid approaches. As discussed above, these hybrids generally involve use of marginal customer and distribution costs reconciled to customer and distribution revenue requirements; an embedded cost based transmission cost allocation; and a stranded cost allocation based either on cost causation or prior Commission set rates. The efficiency and/or equity of the hybrids is less than fully clear. Moreover, any time there is a large reconciliation between total marginal costs and total revenue requirement, questions arise as to the best ways to promote economic efficiency, while also reflecting equity.[38]

Embedded costs can also provide a cost basis for designing rates. They differ from marginal costs in that they are historic rather than forward-looking. Embedded cost studies attempt to determine the basis for the underlying components of the utility's revenue requirement and their "cost-causation"; thus, their goal is equity

[37]Indeed, we have often departed from EPMC, even substantially, to accommodate other rate design objectives.

[38]In our most recent electric rate design proceeding, we expressed concern about the use of the EPMC methodology in light of a large reconciliation amount, questioning the validity of the resulting price signals and the equity of the resulting allocations. Although we did not abandon the approach, we indicated that it would represent only a starting point for pricing decisions. Docket No. 95-052 Order at 37-40, 43.

rather than economic efficiency. Embedded cost allocations are often controversial because there may be numerous reasonable allocation approaches that can significantly impact the results.[39]

We recognize the deficiencies with embedded studies; however, if done properly, they can provide a measure of equity. Moreover, we should not abandon the examination of embedded cost allocations until we have more confidence that marginal distribution costs can be reliably measured such that they would be usable for rate design. Although efficiency will remain our primary objective in designing rates, we will require the filing of an embedded cost study along with a marginal cost study in the post-retail access rate design proceeding.[40]

[39]It is for this reason that the Commission has indicated that embedded cost allocations tend to be "arbitrary." Docket No. 95-052 Order at 38; Docket No. 89-068 Order at 26.

[40]We disagree with CMP that the ERRA requires class allocations based on marginal cost. The ERRA refers to rates that "reflect" marginal costs at different voltage levels and times-of-use, which is a rate design directive that we intend to follow. We do agree with CMP, however, that efficiency can be pursued through intraclass rate design and flexible pricing.

## IV. STANDBY RATES

### A. General Considerations and Approach

The Restructuring Act directs the Commission to establish standby rates as part of this proceeding. 35-A M.R.S.A. § 3209(2). This topic has been one of the most contentious in the proceeding. Among the issues debated are whether it is appropriate to impose charges based on contract demand, whether the diversity of standby customers' loads should be taken into account when determining their responsibility for T&D costs, and how to recover stranded costs from standby customers.

Our decision regarding the design of CMP's standby rates, however, is guided not by our views on these specific aspects of standby rate design, but by our overall principle that, to the greatest extent possible, there be no losers on March 1, 2000. The best way to achieve this objective for standby service is to charge generating stations or facilities and self-generators pursuant to the applicable full requirements core class tariff. For the reasons discussed more fully below, the ratchet provisions contained in CMP's existing full requirements tariffs would continue to apply for standby service.

CMP's proposal would apply different treatments for self-generators (electricity end-users that provide some of their own electricity) and stand-alone generators (facilities engaged solely in generating and selling electricity). Under CMP's proposal, self-generators would take service under a newly designed standby rate. Stand-alone generators would take service under the applicable full requirements core rate, as they do now, but with the demand ratchet retained. CMP calls the service provided to stand-alone generators "station service". All customers with standby or station service loads of less than 400 kW would also continue to pay for their service under core rates, which CMP proposes would no longer have demand ratchets.

CMP's proposal to treat these two groups differently appears motivated by its general objective that March 1, 2000 rates be designed to minimize adverse bill impacts to its customers. In keeping with that objective, CMP proposes to treat station service customers on a similar basis as they have been treated in the past. In contrast, CMP indicates that, because its proposed standby rate will largely apply to new self-generators, bill impacts are a lesser concern.

As discussed previously, we have adopted a "no losers" principle to govern our rate design decisions in this proceeding. We consider this principle applicable not only to customers currently taking standby or station service, but also to current full requirements customers with potential self-generation alternatives. We disagree with CMP's characterization that customers are not affected by a substantial increase in standby rates simply because they are not now standby service customers. Clearly, such an increase would increase the cost of the customers' self-generation alternatives, thereby reducing the amount by which electric rates would have to be discounted to compete. We find that such a change should not be made at the same time retail access begins for the same reasons articulated previously in this Order that changes should not be made to core class rate design.

Thus, we find that all standby service, including that provided to generating stations or facilities and to customers with self-generation, will be provided pursuant to the tariff of the full requirements class in which the customer would take service based on size and voltage level. The one difference between full requirements and standby service will be that standby service will be subject to demand ratchet provisions similar to those contained in CMP's current rate design, whereas the demand ratchet will be eliminated for full requirements service.

Finally, we note that our ability to apply the “no losers” principle here, as elsewhere, is premised on current expectations about future events. If the future does not unfold as we expect, we may revisit this decision in Phase II.

In the following sections, we discuss in more detail the issues raised regarding standby and station service rates. Although many of the issues do not affect the standby rates that will be effective on March 1, 2000, the discussion will provide guidance to the extent standby rate design must be addressed in the post-retail access rate design proceeding.

B. Size Criteria

CMP argues that requiring small customers with standby loads to take service under a separate standby rate would not be cost-effective because of high transaction costs and the relatively small impact that these customers have on distribution planning compared to large standby customers. CMP, therefore, proposed that small customers continue to take standby service under standard core rates. The Company proposes 400 kW as the dividing line between small and large customers.

We find CMP's proposed dividing line to be reasonable. CMP should, therefore, charge all customers with standby demands of 400 kW and above pursuant to the standby rates set in this proceeding.

C. Contract Demand Charge

Under the Company’s proposed standby rate, contract demand charges would be used to recover transmission, distribution and stranded costs. In other words, a customer would be charged based on the amount of demand contracted for, rather than on the amount actually used. The Company proposes that separate peak and off-peak contract demands be established, with incremental off-peak demand charged at a lower rate to reflect the diurnal variation in distribution costs. This provides an incentive to use the service during off-peak hours.

For the reasons discussed in this and the following two sections, as a theoretical matter, the use of a contract demand for billing purposes would be reasonable for standby service as long as the unit charges to recover the allowed revenue requirement are developed on the basis of contract billing demands. Contract demand is a reasonable billing basis for standby service because of the uncertainty of actual demands and because standby service, by its very nature, is a reservation service. The customer is purchasing a reservation of capacity to serve its contract demand whenever required.[41] Billing on a contract demand basis provides a reasonable match between the billing method and the costs that are incurred to provide the standby customer with service.

D. Distinction Between Diversity and Reservation

The importance of the disputes concerning reservation and diversity has been much reduced by our decision not to create a dramatically redesigned rate for standby customers. Because it is possible this debate will arise again in the future, however, (if, for example, the rate pressure created by departing customers becomes intolerable), we offer our preliminary conclusions concerning the issues raised by the parties.

Much of the debate in this proceeding regarding standby service has focused on whether diversity should be considered when determining the costs that a standby customer imposes on the system, and whether that customer should be charged on the basis of a contract demand as opposed to an “as-used” basis. Some of the arguments suggest that parties believe these issues are one and the same; either diversity is accounted for, or a customer should be charged on a reservation basis -- i.e., using contract demand.

Diversity, in the first instance, is a cost question. What loads of a customer are relevant to system design, expansion and costs? Does a customer add to the costs of the system based on the customer’s maximum demand whenever it occurs, or on the basis of its demand at the time of the relevant system peak? The system at issue could be the regional or local transmission system, or a circuit on the distribution system. For transmission, CMP asserts that cost allocation is FERC-jurisdictional and proposes to charge standby customers its FERC-approved transmission rate based on the customer's contract demand. With regard to local distribution system costs, the Company maintains that it adds capacity on a kW for kW basis to meet the maximum potential load of large customers (400 kW and above) in addition to the coincident peak loads of all small customers on the system. As a result,

[41] The OPA suggested an option where customers could take “interruptible” reservation service. We believe such an offering might well be appropriate especially where a new customer, for whom no distribution investment has yet been made, is coming onto the system. We will explore the merits of such service if the issue of standby service is reviewed in our post-restructuring rate design case.

CMP states that diversity is not recognized when planning the distribution circuit that contains the load of large customers.

The key point is that the impact of diversity on cost is an empirical question, not a theoretical one. If a system is actually built to meet the peak demand of all other customers on a distribution circuit plus the full demand implied by the reservation, then the costs associated with that reservation are the responsibility of the reserving customer. The question of whether CMP should design its system that way is interesting, but wholly distinct.

Although parties have questioned the efficiency of CMP's expressed planning criterion, given this criterion, it would be appropriate to ascribe distribution costs to large customers based on their maximum potential demand. For standby customers, this is their contract demand.[42]

### E. Recognition of Diversity

In this section, we address in more detail whether, and how, the diversity of standby service loads should be treated in assigning cost. Diversity is defined as the ratio of a customer’s (or a class’s) highest demand (whenever it occurs) to that customer’s (or class’s) demand at the time coincident with the peak on the relevant system. The relevant system could be generation level, some portion of the transmission system, or a local distribution circuit. Savings from diversity result when the utility can build its system to meet the coincident loads of its customers rather than the much higher sum of individual customer maximum demands. These savings, or diversity benefits, are generally distributed among customers in proportion to their contributions to system diversity. This is typically accomplished by allocating system costs in proportion to coincident demands. The parties agree that diversity is greatest at the generation and bulk transmission levels, and declines as one moves from the generator to the meter. For example, for a facility dedicated to a single customer (e.g., meter), there is no load diversity. However, as long as equipment serves at least two customers, there will be some load diversity on that equipment, unless the two customers have identical load patterns. The issue, then, becomes a quantitative question of how much diversity exists and how (or if) it affects the planning and construction of the system.

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[42]Whether the costs assigned to a customer or group of customers are recovered through usage charges, demand changes, or some combination has no relevance to the cost assignment question. If the customer’s actual load over the year could be predicted with some degree of certainty, then an “as-used” rate could be designed to recover the costs appropriately ascribed to standby customers. If actual load is uncertain, it would be difficult to design an “as-used” rate that would recover the right revenue. In such a case, using a contract demand charge would be preferable.

In this proceeding, there has been much testimony and argument regarding the diversity of standby customers' loads and the cost and revenue responsibility consequences of this diversity. That the loads of standby customers are more diverse than full requirements customers is not in dispute. What is in dispute, however, are the cost and revenue implications of that diversity.

1. Transmission

There seems to be little disagreement that diversity benefits exist at the transmission level and that CMP takes these benefits into account when it decides how much transmission capacity it requires. However, CMP argues that FERC has jurisdiction over retail transmission rates and that FERC Order No. 888 requires that behind-the-meter generation be included in calculating the transmission charge. For a standby customer, the Company argues, this means that transmission cost responsibility should be set on the basis of the customer's maximum potential demand (i.e., contract demand) rather than its actual contribution to the monthly coincident peaks; CMP asserts that FERC would require the latter for requirements customers. In other words, the Company argues that the diversity of standby customers cannot be considered in determining their revenue responsibility for transmission. FPL Energy Maine, Inc., the Independent Energy Producers of Maine and S.D. Warren Company (the Generators) and the IECG, have each taken issue with CMP's interpretation of FERC's "behind-the-meter" ruling, arguing that it does not apply to the determination of transmission cost responsibility for retail customers.

Although the "behind-the-meter" debate has received much attention in this case, it does not appear particularly relevant, even to CMP's proposed standby rate. Although CMP asserts that FERC rules require a customer to pay for transmission based on the size of the customer's own generation, CMP did not actually propose to charge any standby or station service customer in this way. Rather, CMP proposed to charge for transmission based on contract demand in the case of a standby service and ratcheted demand in the case of station service. For both, transmission cost responsibility would reflect some diversity benefits, those of the full requirements class,[43] but not the additional benefits CMP acknowledges it would realize in terms of savings on its transmission system from the much greater diversity of standby customers' load.

The "behind-the-meter" issue has even less relevance to the top-down, bundled T&D standby rate that we adopt in this proceeding. This approach does not involve any direct allocation of transmission costs to standby customers, or a separately charged rate component for transmission. Moreover, as discussed in

[43]Our interpretation of the Company's standby rate as derived in the Dumais, Peaco, Parmesano Surrebuttal at Ex. DPP-46 is that the FERC transmission rate charged to standby customers on the basis of contract demand is effectively scaled down to reflect the transmission cost responsibility of the corresponding core class, which is set using the core class' coincident demand.

section III(D), we would seek allowance from FERC, if necessary, to allocate and design the transmission portion of CMP's bundled T&D rates, consistent with underlying costs and other rate-setting objectives.

2. Distribution

The analysis of the diversity issue differs with respect to distribution costs. The Company has stated that it plans for distribution capacity to meet the loads of large customers (400 kW and above) on the basis of their maximum potential loads, not on the basis of their coincident loads. Therefore, CMP argues, it is inappropriate to account for the diversity of standby customers' loads when determining their responsibility for distribution costs. The IECG, the Generators and RWS all disagree. They provide empirical evidence that shows that standby customers contribute little to the coincident system peaks. They then argue that the Company either actually does, or should, account for this diversity when allocating distribution costs to standby customers.

CMP asserts that the coincidence factors of standby customers are irrelevant. CMP claims that due to the size of a standby customer (which CMP proposes as 400 kW and above) it would size the distribution circuit to meet the customer's maximum potential load. Specifically, CMP describes its distribution system planning criterion as the coincident loads of small customers plus the maximum potential load of large customers. James Begin, CMP's Manager of Transmission and Distribution Planning, represents that the size and unpredictability of these large standby loads require that CMP size circuits on a kW-for-kW basis to be prepared to meet these customers' maximum loads whenever they occur, including at the time when other customers' coincident loads are highest. Mr. Begin further states that on CMP's system there is generally only one large customer on a circuit together with a number of much smaller customers; as a result, large customers tend to dominate the load on their circuits.

The intervenors' responses to Mr. Begin's testimony include both disbelief and criticism, and in some cases both. The notion that utility systems are planned to meet the relevant coincident loads of customers is the conventional wisdom, and results in one of the primary rate design challenges: how to allocate those diversity benefits among classes of customers. CMP's position on this issue is also somewhat surprising given the fact that CMP's cost studies allocate distribution costs among full requirements customers in a way that reflects the load diversity of customers both small and large.

The parties appear to question the prudence of CMP's distribution planning criterion. However, no party has presented evidence or proposed a remedy for any imprudence in this regard. As a general matter, costs should be assigned to reflect the way in which the system is actually planned and costs are incurred. It is conceivable that CMP would not account for the diversity of large customers when there is a single large customer on a circuit with a number of smaller customers. In such a case, a large customer’s requirements could overwhelm the requirements of other customers. If CMP’s distribution system costs are incurred as CMP describes, it is appropriate to allocate the costs among customer classes using the sum of customer maximum demands for large customers and the relevant coincident load for small customers. This is also discussed in Section III.B.2 with respect to full requirements service.

F. Stranded Cost Recovery

Under CMP's proposal, the recovery of stranded costs from standby customers is based on the costs that are assigned to full requirements customers on the core rate corresponding to the standby customer's load and voltage level of service. More specifically, the Company determines the total stranded costs to be recovered from customers served under the core rate and divides that amount by a measure of usage equivalent to the total contract demands of those customers. As a proxy for contract demand, CMP uses the sum of the annual maximum measured demands of the customers on that rate schedule. The resulting kW charge is equivalent to the rate that would apply to customers on that core rate if the class' stranded costs were to be recovered from core customers on the basis of a contract demand charge. This kW charge is then applied to the standby customer’s contract demand to determine its stranded cost obligation. The result of CMP's approach is that a standby customer would pay an amount of stranded costs that is comparable to a full requirements customer with the same demand and voltage level of service.

Parties have objected strongly that this aspect of CMP's proposal would constitute an exit fee which is proscribed by the Act. We make no finding whether CMP's basic approach would constitute an exit fee under the Act. However, the approach is inconsistent with our “no losers” principle; therefore, we will not adopt it.[44] CMP’s proposal would significantly increase the stranded cost responsibility of customers who self-generate or who have self-generation alternatives. For the reasons discussed in this Order, the beginning of retail access is not the time to make such a change.

Some parties suggest that use of a contract demand charge for stranded cost recovery would itself be an exit fee. In preceding sections, we discussed why recovering costs through a contract demand charge would not by itself be unreasonable or treat standby customers unfairly. Different billing methods are frequently used to recover the same costs from different groups of customers. The most obvious example is the recovery of demand costs from some customers through demand charges, and recovery of these same demand costs from other customers through energy charges. The test for reasonableness when comparing two billing methods is whether they would recover essentially the same revenues if the billing

[44]In any case, it is irrelevant under our “top down” approach and our decision to retain the existing rate design for standby customers.

information were available to permit either method to be used. CMP has developed the stranded cost charge for standby service by simulating recovery of full requirements stranded costs as if done on a contract demand basis. All of CMP's stranded costs could be recovered this way. CMP does not propose to do so because requirements customers' actual use is fairly predictable; hence, as-used billing can be relied upon to recover the proper revenue. As noted above, that is not the case with standby customers, and so a contract demand billing method is used. Thus, the use of a contract demand charge does not, per se, constitute an exit fee, as suggested by some parties.

The real question, then, is whether a standby customer with a contract demand of a particular amount, e.g., 1 MW, should pay the same amount of stranded costs as a requirements customer with 1 MW of actual demand. Because requiring standby customers to do so would significantly increase their responsibility for stranded costs relative to today, such an approach is inconsistent with our "no losers" principle. Thus, we reject CMP's proposal for stranded cost recovery from standby customers.

### G. <u>Stand-Alone vs. Net Generators</u>

Under CMP's approach, station service would be available only to stand-alone generating plants. Station service would be provided at the rates contained in the full requirements core tariffs, and a ratchet would apply to station service demand. All other customers would take standby service to back up their generation. The Generators argue that customers whose generation on net exceeds their load should be placed into the station service category because net generators (like stand-alone generators) paid for the T&D facilities to accommodate their generation.

Because we will not differentiate between station and standby service customers, the issue largely becomes moot. However, we address below three specific issues raised by the Generators that remain relevant.

### H. <u>Incremental T&D Costs to Provide Station Service</u>

The Generators argue that net generators have paid for any T&D facility that CMP installed to accommodate the net generator's output. Moreover, the Generators argue that net generators, or their customers, also pay ongoing wheeling charges to CMP for the cost of maintaining a T&D system capable of delivering the net generator's output to its load. Consequently, the Generators argue that there is no incremental cost to provide standby T&D service to net generators. Therefore, an appropriate rate to net generators would be limited to a per customer allocation of customer account expenses and customer service and information expenses, marked up by an appropriate EPMC factor (the same as for all other classes) to recover from these customers their "fair share" of stranded costs and other sunk costs.

The Company takes issue with the Generators' assertion that net or stand alone generators pay for all of the upgrades necessary to deliver their output to the grid. It states that generators only paid for immediate, incremental system needs; if excess capacity existed when a generator connected to the system, the generator was not required to pay CMP for upgrades to the system. In its Initial Brief, CMP states that:

> Generators did typically pay the costs of hooking their equipment to CMP's system. They did not make upfront payments for the entire system they use, e.g., the generator in many instances did not contribute to the cost of the distribution substation for that customer's circuit. Nor do they pay anything for the upstream costs incurred in serving them.

However, the major thrust of the Company's argument seems to be that, regardless of what connection costs were borne by the generator, such payments do not absolve the customer from any future, ongoing charges to remain connected and obtain the provided benefits.

The critical aspect of the cost responsibility of stand-alone or net generators has less to do with the initial upgrades that were required and the up-front payments that were made at the time of the connection and more to do with the ongoing contribution to T&D costs incurred as the T&D system is continually upgraded and expanded to meet the growing needs of all of CMP's customers, including the stand-alone generators. The more persuasive argument appears to be that generators, or their customers, will continue to pay the T&D delivery charges (as appropriate) for all of the power that is sold by these generators. As a result, there is a contribution to the ongoing cost of the T&D system, including the cost of all necessary future upgrades, just as with all other customers who use the CMP T&D system.

However, this fact does not mean that the generators should pay nothing for their use of the T&D system when they purchase station service. The Generators do not raise the question of whether customers that purchase their output ought to pay T&D delivery costs associated with that output. Similarly, it is reasonable that station service customers, as retail customers purchasing the output of some other generator, bear their proportionate share of the costs of the T&D system when it is used to deliver energy to them. There is no difference between an end-use customer using the energy produced by a generator to illuminate the lights in a house or a factory, and the generator using electricity produced by some other generator to illuminate the lights in his generating plant when the plant is not operating. Both are end-use retail customers, and both should pay the tariffed rate for T&D service. As CMP argued in its Reply Brief:

> CMP does not identify which specific customers are imposing incremental costs on the system in designing rates . . . Instead, the challenge to rate designers is to identify cost drivers and to use those drivers to develop generally applicable rates to recover the Company's revenue requirement.

CMP will not recover any additional revenues by charging these stand-alone generators for the use of the T&D system. The question is one of cost allocation; the Company will have the opportunity to recover its allowed T&D revenue requirement. The issue is who will pay the Company's costs. If station service customers do not pay when they use CMP's system to obtain energy, other customers will make up the difference.

Finally, we disagree with the Generators' fundamental premise that there are no incremental T&D costs to meet station service load. Consider the following example of a 30 MW generator that has a 2 MW station service load. The Generators' argument is that ample T&D capacity must exist to accommodate its 30 MW output and, therefore, there are no incremental T&D costs to serve its much smaller 2 MW load. However, when the 30 MW generator is down, the loads it would otherwise serve must still be met; thus, the 30 MW of T&D capacity associated with this load would continue to be utilized. If, at the same time, the generator requires 2 MW of station service, the T&D system must have sufficient capacity to meet the 30 MW plus the 2 MW increment of station service load. Thus, it is clear that the station service load is incremental to the load that its generation normally serves.

I. Stranded Cost Responsibility of FPL

FPL raises a separate issue with respect to stranded costs in station service rates. FPL argues that, because under NEPOOL rules the station service loads of CMP-owned generating plants never contributed to CMP's capacity requirements, CMP incurred no generation-related stranded costs to provide them service. Therefore, FPL argues, it should not be charged any stranded costs associated with the station service requirements of those generating plants. CMP's response to this argument is that the total charge to FPL under its proposed standby rate is reasonable. CMP also notes that it does not trace stranded costs to customers, which is the implication of FPL's position.

FPL has accurately described NEPOOL's treatment of the station service loads of CMP-owned generation plants. As noted by FPL, NEPOOL rules allowed utilities to deduct their own station service from their monthly peak loads for the purpose of calculating capability responsibility. However, FPL's argument overlooks CMP's planning criteria for generation, which consider energy as well as capacity. Even if the station service loads of CMP-owned generating plants did not contribute to its capacity requirements, there is no evidence that these loads did not contribute to energy requirements. Moreover, we agree with CMP that stranded cost responsibility should not be tagged specifically to particular customers based on historic conditions. To do so could lead to outcomes, for instance, whereby new customers would pay no stranded costs. There may be a rationale for such an outcome based on the fact that new customers did not cause CMP to incur any stranded costs. However, we decline to adopt a system with different rates for "new" and "old" customers; all customers should be charged comparably based on their current use of CMP's system.

J. Retaining the Demand Ratchet

The Company has proposed to eliminate the demand ratchet for full requirements customers but retain the ratchet for station service customers. As noted earlier, we find the use of a ratchet to be appropriate for all standby service customers because of the uncertainty of their actual use, and the resulting difficulty of designing an “as-used” rate that will recover the proper revenues. However, we modify the Company’s proposed retention of the ratchet as described below and adopt it (as modified) for standby (including station) service.

CMP is proposing to eliminate the demand ratchet for full requirements service. This effectively reduces the billing units of the class. The Company must then apply a higher unit demand charge to the unratched billing demands in order to recover the same revenue. It is internally inconsistent to then use these same unit demand charges to recover revenues from standby service customers using ratchet demands. That would lead to an over recovery of these costs from standby service customers. It will be necessary, then to calculate a separate, ratcheted demand charge for these customers or to develop a factor to apply to the full requirements demand charge. The demand charge for standby service should be equivalent to a charge calculated by dividing the demand-related costs allocated to the core rate class by the estimated ratcheted billing demands for all customers in the class, including the standby service customers.

## CONCLUSION

In this Order, we have attempted to resolve, to the greatest extent possible, the methodological issues involved in setting Central Maine Power Company's revenue requirements, stranded costs and rate design at the start of retail access. As we have noted throughout this Order, many items must be updated in Phase II of this proceeding and CMP's Phase II filing. CMP is directed to make a Phase II filing consistent with the findings and conclusions contained in this Order. The Examiners in this matter will soon issue a Procedural Order which will schedule a conference of counsel to discuss among other things, the timing and contents of CMP's Phase II filing. At the conclusion Phase II, we will establish the actual amounts authorized for revenue requirements and stranded cost recovery and set rates for CMP to be effective March 1, 2000.

Dated at Augusta, Maine this 19th day of March, 1999.

BY ORDER OF THE COMMISSION

Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 30 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320 (1)-(4) and the Maine Rules of Civil Procedure, Rule 73 et seq.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320 (5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.